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Mr. David S. Guzy
Chief, Rules and Publications Staff
Royalty Management Program
Minerals Management Service
Bldg. 85, Denver Federal Center
P. O. Box 25165 – MS 3021
Denver, CO 80225-0165

Re: Further Supplementary Proposed Rule
Oil Value for Royalty on Federal Leases
64 FR 73820, December 30, 1999

Dear Mr. Guzy:

These comments are submitted on behalf of Shell Exploration & Production Company and its affiliated companies, Shell Offshore Inc., Shell Deepwater Production Inc., Shell Frontier Oil & Gas Inc., Shell Deepwater Development Inc., hereinafter collectively referred to as "SEPCo". Shell has previously commented on earlier versions of this proposed rulemaking and SEPCo adopts by reference those previously filed comments. SEPCo has also participated in and reviewed the joint industry comments submitted by API and adopts them also by reference. Rather than repeat previous Shell comments, we will focus primarily on the new features of this proposal.

We continue to believe that there is an area of common ground large enough to resolve the differences between MMS and Industry. We applaud the steps taken by MMS to reach that common ground in the area of non-arm's-length transportation allowances. The inclusion of the allowance of 10% of the capital cost when coupled with the application of a fixed rate of return after a transportation system has depreciated below 10% or the original value has helped to somewhat mitigate the fundamental unfairness of setting the non-arm's-length allowance at the operating and maintenance expenses when the pipeline had been fully depreciated. However, the rate of return of Standard and Poors BBB bond rate (presently around 7%) is far too low for this concession to provide meaningful benefit (10% of 7% equates to only 0.7% or .007 times the capital investment). Although the actual S&P BBB rate obviously varies over time, it has historically tracked a level in the economy similar to that represented by 7% today. Seven percent (7%) or its future equivalent is an inadequate rate to calculate the value of the transportation allowance and falls significantly short of reflecting the value of the service being provided.

MMS comments at workshops indicate that this rate has apparently been chosen as a proxy representative of the cost of capital to the lessee and it's affiliated pipeline. This rate is not appropriately reflective of the cost of capital when considering both debt and equity financing. We also believe the rate of return should reflect more than the mere cost of capital. A rate of return should be provided which more appropriately reflects a return on the capital investment made in the pipeline considering additional factors such as compensating for the risk incurred in operating the line, including elements such as capacity under-utilization of the line and financial liability for operation of the line arising from property, environmental and personal injury. We believe that of the MMS options presented, the MMS should increase the rate of return to at least two times S&P BBB Moody's bond rate. The doubling of this bond rate would come closer to more fairly compensating for all three of the elements: cost of capital, return on capital investment and risk assumed.

We commend MMS' recognition in the proposed rule of the inherent unfairness of prohibiting a new third party owner from depreciating a pipeline that had been previously depreciated by the prior owner. We completely agree that the new third party owner should be allowed to include its new capital investment in calculating the non-arm's-length transportation allowance depreciation factor even though the pipeline may have been either partially or completely depreciated by the previous owner.

SEPCo affirms MMS retention of the option to take a non-arm's-length transportation allowance based on the capital investment multiplied by a fixed rate of return with no depreciation as provided in 206.111(b)(1) or (2). With the exclusion of the tariff as a measure of non-arm's-length allowance, MMS should also further clarify that this method would be available to pipelines that had previously utilized tariffs as their allowance basis for the non-arm's-length calculation.

We have serious concerns that the production of records needed to prove actual costs on tariff lines will place MMS in conflict with the FERC restrictions on treatment of affiliates. It is our understanding that FERC regulations prohibit a common carrier from favoring its affiliates. Production of that data to a related entity for purposes of justifying a transportation allowance could require the common carrier pipeline company to also provide the same proprietary data to unrelated third parties. We believe it is inappropriate for the MMS to implement requirements for data production which conflict specifically with FERC requirements to the prejudice of the regulated pipeline entities. We request MMS to reconsider this position in light of the conflict. The solution is not easy. Industry has offered two suggested approaches to resolve this conflict (e.g. MMS accept oil pipeline tariffs or rely on the market place to establish the rates to comparable costs paid by third parties). We encourage MMS to resolve this conflict by modifying the rule or by resolving procedural conflicts between MMS and FERC before making the proposal final.

We continue to urge MMS to recognize other comparable sales methodologies (e.g. tendering) as a valid methodology for valuing royalty production at the lease in areas such as the Gulf of Mexico. SEPCo's experience with our crude oil tendering program in the Gulf of Mexico strongly illustrates there is a viable market at the lease. As of January 1, 2000, approximately three-fourths of SEPCo production is sold at arm's-length prices. Furthermore, such arm's-length transactions at the lease avoid the complexities and uncertainties associated with adjusting from a downstream sales point to arrive at a lease value. We strongly suggest MMS expand their proposed comparable sales methodologies to include tendering in the Gulf of Mexico.

The definition of affiliate has been modified to remove the presumption of control when ownership of an affiliate is between 10 and 50%. Instead, certain criteria are advanced to make a determination on affiliate status. We appreciate the effort of the agency to articulate objective criteria but believe further work is needed to clarify the matter. At the recent workshop, participants raised several practical difficulties with this change. First, there is no procedural mechanism under which the MMS can permissively or mandatorily grant guidance on this issue. Several people were confused on the meaning of the phrase in 206.101(2)(iii) "operation of a lease, plant or other facility." Does this mean joint ventures on OCS leases are to be considered affiliates? If they are, are they to be regarded as affiliates only for purposes of the lease subject to the joint venture agreement or are they considered affiliates for all other purposes? It is also unclear how the term "affiliate" is to be applied when a percent of ownership of a pipeline is held by a legal entity when the legal entity itself is also made up of affiliates. For example, a legal entity may be made up of 50% Shell plus 50% third party. That entity in turn owns 20% of a pipeline. When SEPCo is the lessee moving through the pipeline does SEPCo own for allowance calculation purposes 10%, that is, 50% of the 20%, or does MMS maintain that SEPCo is charged with the full 20% ownership? In this situation, a determination of affiliation under the MMS criteria would ultimately require a full review of both the pipeline ownership agreement as well as a review of the agreement creating the legal entity that owns only a small percentage of the pipeline.

The points we raise may appear on the surface to be mundane nuances of not particular significance, but they are not. Given the growing trend toward joint operations, alliances, and other complex business affiliates and arrangements, it is important that the definition of "affiliate" be clarified so companies can easily and accurately determine affiliation. We commend the MMS for its work in this area, but urge the agency to continue to work with industry to further clarify the meaning of this section.

Application of the affiliate definition also causes concern. For example, Shell and Exxon/Mobil own interests in Aera Energy, a California lessee. According to the regulation, when a lessee exercises certain options for valuation, all of its affiliates must follow the same option. Does this mean that when Aera Energy exercises its options, both Shell and Exxon/Mobil are bound by that election? In other words, in practice, does the affiliate definition flow upward as well as downward for purposes of exercising options that bind affiliates? Some clear examples of how this definition would apply based on these factual circumstances and others raised by commentors would be most helpful to the regulated community.

Although we appreciate MMS changes on the issues of binding determination and second-guessing and know they are well intentioned, they are problematic for several reasons:

1 Circumstances under which value determinations will be given are overly restrictive. Excluded from consideration are matters inherently factual or legally controversial. Almost all royalty questions hinge intently on the facts. Most thorny issues involve legally controversial determinations.

2. The lessee is left with no way to resolve lower level disagreements with MMS staff other than risking audit non-compliance, while the agency's position is protected as long as a judicial decision, law or regulation has not intervened. In other words, all possible agency options are maintained in the process.

3. The MMS has failed to clarify that a lessee acting contrary to a non-binding staff level decision is free of liability for civil penalties and possible False Claims Act liability for filing false forms. The lessee is left in this position based on a staff opinion that has no appealability. This omission is particularly disconcerting in light of the ongoing litigation over oil valuation methodology and the obvious need for good faith guidance to a lessee who is genuinely seeking to apply the regulations correctly. The 1988 regulations at least provided for application of such requested method during the pendency of the decision making process. We believe the current regulation should include a clear statement on liability for staff decisions for which there is no administrative appeal.

4. The proposal still creates uncertainty and unduly levers the agency's position by requiring underpayment as the sole mechanism to secure binding determinations in the absence of Secretarial decision. Since underpayment carries the risk of interest and penalties, the lessee must either concede to the agency staff position or assume the financial risk of interest, penalties and possible False Claims Act liability. MMS is even left the option to "select" the controversy that will resolve the issue through the use of the audit process. We believe this procedure is unfair and unbalanced.

5. Section 206.107(e) remains unclear on whether changes in MMS royalty regulation would be applied retroactively to overturn not only MMS staff decisions but even Secretarial decisions. This provision should clearly restate the general principal of law that changes are not to be applied retroactively.

6. The small number of valuation determinations described in the MMS commentary appears to indicate intent to rarely issue such determinations. We believe that the statistics for value determination requests under the 1988 regulations contradict such an assessment and indicate a policy decision on the part of the agency to practically eliminate issuance of such determinations. We believe that the lessees should be offered the opportunity for valuation guidance that has a higher degree of certainty when requesting directions on payment and compliance with the regulation.

We believe that MMS should also provide clear transitory provisions for application of the new regulations which would address either procedural or substantive difficulties which will occur as a result of these new regulations. For example, the data needed to value oil or establish transportation allowances may not be available to lessees. Although much of the data required could be generated, in many instances downstream affiliates or divisions of the lessees do not maintain records and accounts in the same manner as lessees customarily do for the MMS. For example, common carrier pipelines follow a FERC mandated depreciation process that does not coincide with MMS depreciation requirements. These pipelines would be required to recreate this information in order to determine the allowance. This process alone will take a substantial administrative effort. That effort is complicated by the fact that in many instances original evidence of capital cost, such as construction invoices and AFEs, have long since been destroyed by routine record destruction. However, MMS auditors routinely request this original documentation. Adequate time should be provided to calculate the data on individual pipelines and some specific guidance should be given for audit protection for common carrier pipelines which no longer have original records.

System changes will likely be necessary between the upstream affiliate or division and the downstream affiliate division of integrated companies in order to generate and transfer data captured. The needs and practices of downstream accounting do not currently envision data capture as proposed by the MMS. Downstream and upstream accounting contrary to MMS's supposition does not precisely match since the needs and regulatory requirements are different. The cost and time necessary to achieve this have not been considered in the rulemaking. MMS is requested to allow at least twelve months from the date the regulations are finalized to transit between the old and new regulations.

Other transition issues include providing guidance to common carrier pipelines as to what basis they are to calculate transportation allowance for non-arm's-length transactions now that tariffs are disallowed. For example, which transportation calculation is available to former tariff pipelines? Should the pipeline use the original capital cost times a fixed rate of return even though it may be fully or completely depreciated, or may the pipeline start over again depreciating the line with a fixed rate of return on undepreciated capital and O&M expense? Substantive guidance on transition issues such as these and others raised by commentors should be included in any final publication of the regulations.

We attach hereto more detailed comments on individual sections of the Federal Register proposal. We appreciate the opportunity to make these comments during the rulemaking process.

Sincerely yours,

Larry W. Wooden

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Shell Exploration & Production Company

Attachment

Appendix A

I. General Considerations

The merger of concept of marketable condition with the duty to market is contrary to the intent of the royalty bargain agreed in the lease and applicable mineral statute. Historically, the royalty owner has traditionally received only a fractional part of the production or production revenue "at the well", where the hydrocarbon from which the royalty is paid came into being. Royalty did not include any value added by the lessee through entrepreneur skills taken "downstream" away from the lease. The reason for this is that royalty for the landowner lessor was a hedge against uncertainty. Since the mineral lease itself is conditioned on an uncertain hydrocarbon discovery and since the landowner wants to share none of the costs or risks of determining the presence of hydrocarbons, the concept of royalty emerged. As such, royalty is paid at the lease (MMS and industry both agree on this) on the value of the hydrocarbon free of the cost of production. MMS now wants to be paid on the value of production away from the lease but maintains that the "duty to market" is part of the cost of production, which must be borne solely by the lessee itself.

It is clear that a lessee must bear all "costs of production" and that royalty is free of such costs related to production. Phrased another way, the issue is when is production complete so as to fix royalty. Until recent years it was generally accepted that production occurred for royalty purposes when oil and gas had been captured at the well on the lease. Under this theory, the costs of marketing, transporting, compressing and processing were charged proportionately to the royalty interest since they occurred after capture and were not part of production costs. This concept logically follows the concept that the lessor did not bargain for a royalty on the entrepreneurial activity of the lessee away from the lease after production was completed.

Around 1940, Professor Maurice Merrill advanced the concept that the costs of production were not complete until the production recovered had been prepared for market or put into a marketable condition for possible sale. This concept of marketable condition was present in the 1988 regulations. A number of recent cases in Oklahoma, Colorado and Kansas have held that production is not complete until the hydrocarbon is captured and made marketable. However, once production is captured and in marketable condition even under this concept, later costs occurring away from the lease are shared if the lessor wants to base value on entrepreneur skills away from the lease which have increased product value.

The MMS OCS lease form contains no actual duty to market. In federal leases, MMS can only assert that there is an implied duty to market. However, MMS and the current regulations misstate the law by stating that the essence of the duty to market lies in the "creation and development of markets". 64 FR 73822. The implied covenant <u>only</u> imposes a duty upon a lessee to act at, on, or near the lease to find a sale or disposition of the product. This implied duty to market imposes no duty to act away from the lease to create a market. See *Craig v. Champlin Petroleum Co.* 435 F2d 933 (10th Cir., 1971). In short, MMS has used the concept of gross proceeds to assess royalty not only on production but has expanded the concept of gross proceeds to assess royalty on business skill and efforts of the lessee which enhance the value of hydrocarbons long after production.

2. Special Provisions

§206.100(b)(2)
The OCS lease allows assessment of royalty only on "production". Gross proceeds can be validly assessed only on "production". Production is complete when the hydrocarbon is captured and in marketable condition for possible sale. All parts of the regulation contrary to this provision are invalid to the extent value is assessed on business efforts and costs incurred by the lessee away from the leases after production has occurred.

§206.101
"Affiliate" – Revise the definition to clearly specify a procedure to secure a determination of affiliation. Resolve substantive conflicts over application of the definition as noted in cover letter. Clarify the intended use of the phrase "lease, plant or other facility".

"Exchange Agreement" - The examples given are overly expansive and contain fact situations which do not involve transfer of actual barrels of oil.

"Gross Proceeds" - To the extent that the definition attempts to apply royalty to value after production is complete and in a marketable condition, the definition exceeds statutory authority and lease rights.

Payments made to reduce or buy down the price of hydrocarbons have been found to be royalty free. This provision is contrary to *Diamond Shamrock* Fifth Circuit case and the D.C. Appeals case *IPAA v. Babbitt.*

"Lease" - A "joint venture" and "profit share" arrangement between lessees are not and cannot constitute a lease under the enabling mineral statute. Each can only exercise rights granted by an already existing lease.

"Location Differential" - The definition is too limited since it applies only to "Exchange Agreements". The concept has applicability to other arrangements and the definition should recognize this. Location differential and transportation allowance are not overlapping terms.

"Person" - The concept of LLC (Limited Liability Company) should be added. Clarify in "joint venture" the meaning of "when established as a separate entity".

"Quality Differential" - Definition is limited to Exchange Agreements yet differentials may be paid in transportation agreements other than Exchanges. This definition would arbitrarily eliminate them from royalty adjustment, both plus and minus in other transportation agreements.

"Tendering Program" - Clarify as publicly stated at the Houston workshop that tendering is a type of arm's-length transaction. Expand the definition to include Gulf of Mexico production.

§206.102
To the extent this regulation disqualifies an arm's-length market place sale through mere exercise of options, it violates the OCS lease royalty clause and is invalid. To the extent the

regulation in (d) presupposes the arm's-length Exchange Agreement is not actual royalty value, the rule is arbitrary and violates the OCS lease royalty clause and enabling statute. Elections under (d)(1)(I) should at least be allowed by geographic area since even MMS recognizes in these proposed regulations that geographic location impacts value determination criteria. We believe an election should be allowed by field or area since market conditions may effect value. Transportation exchanges have been recognized by IBLA as merely transportation related and have nothing to do with royalty value of the hydrocarbon but only impact the transportation allowance itself.

§206.103

(a) ANS spot does not reflect the value of production at the lease in marketable condition. To establish value by use of this index fails to account for other costs in which MMS must share before establishing value.

(c) MMS use of index to value production violates the OCS lease by arbitrarily fixing value without specific consideration of other factors, such as arm's-length sales of substantial volumes of production at the lease. Although the Secretary has discretion to set value, that discretion is bounded by the enabling statute and the lease. Shell, as of January 1, 2000, disposes of almost three-fourths of its oil production at arm's-length. To require value at index of the remaining portion ignores the lease and arbitrarily moves value away from the lease when value can be readily established at the lease. To do so without consideration of the factual circumstances surrounding disposition and value is arbitrary. In Subsection (c)(2) location and qualify differential were defined only in the context of exchanges. Non-arm's-length sales are not exchanges. The definition of each needs to be adjusted Differentials may be encountered (plus or minus) in ordinary transportation (not just exchange) agreements. The arbitrary required use of index under all circumstances violates the definition of "fair market value" under Section 2 of the Outer Continental Shelf Lands Act, 43 USC §1333 that provides.

> "The term fair market value means the value of any mineral
>
> (1) computed at a unit price equivalent to the average unit price at which such mineral was sold pursuant to a lease during the period for which any royalty or net profit share is accrued or reserved to the United States pursuant to such lease, or
>
> (2) if there were no such sales, or if Secretary finds there were an insufficient number of such sales to equitably establish value, computed at the average unit price at which such mineral was sold pursuant to other leases in the same region of the Outer Continental Shelf during such period.";
>
> (3) If there were no such sales of such mineral from such region, during such period or if the Secretary finds that there are an insufficient number of such sales to equitably determine such value, at an appropriate value determined by the Secretary."

This provision of the Lands Act requires the Secretary to proceed from lease, to region, and only then to his discretion. When arm's-length sales of the high volumes occur as they do for

SEPCo, an exception to the index value requirements for non-arm's-length should be included. Otherwise, for OCS leases, the regulation will potentially violate the enabling statute. MMS should reconsider this provision in light of this and create an exception based on lease and region sales in order to comply with this provision as applied to royalty on production at the lease. Otherwise, something other than fair market value will be paid as royalty.

§206.106
The addition of the phrase "or to market the oil" is contrary to statute and lease. MMS is not entitled to assess royalty on marketing efforts. Literally read under MMS theory, this clause would require Shell to add to the value the costs Shell had incurred (but not deducted) to market the oil. MMS is entitled to royalty on production at the lease. Once production has been completed, MMS must bear its share of costs to enhance value incurred away from the lease through entrepreneurial skills of a lessee. To do otherwise will assess royalty on a value not associated with production.

§209.107
This provision inadequately addresses both certainty and second-guessing. The Secretary has always had authority to issue final determination. The Secretary also had the authority to delegate certain functions subject to internal administrative appeal processes. This provision leaves the lessee at risk from staff decisions, forces the lessee to risk interest or penalties if staff decisions are not obeyed, allows the agency to maintain all options including retroactive regulation or Secretary decision, fails to provide a lessee with any protection from penalties for falsely filing reports under MMS regulations and the False Claims Act. In light of the risk of harm through assessment of interest in cases of disagreement, MMS has created a type of irreparable harm for the interest on underpayment for which there is no judicial remedy

(b)(3) The exceptions to MMS response to value requests are too broad. The categories should be narrowed as indicated earlier.

(e) MMS should clearly indicate this will ordinarily apply prospectively only.

(f) The word "generally" should be removed. The two exceptions alone describe the cases when retroactive application can occur.

§209.109
(a) Remove the reference to royalty in kind. The royalty in kind regulations should be the subject of separate rulemaking.

(b) Clarify that quality and location apply to a category of transactions broader than Exchanges.

206.110
(e) No definition of "transportation factor" has been given. Does this mean that an arm's-length sale at the lease has a transportation factor? To clarify "use" MMS should change to "deduct" from gross proceeds.

(e)(2) No explanation is given as to why an arm's-length sale with a high transportation cost is automatically disqualified as royalty volume. This is contrary to lease terms and enabling statutes.

206.111
Tariffs should be allowed for producer owned and affiliate transportation or the value of the service should be used.

(b)(2) This provision should be retained and be made specifically available to previously used tariff lines.

(d) The phrase "which you can document" should be clarified by the phrase "under standard oil and gas accounting practices". If expenses are allocated, then documents will be limited to standard accepted oil and gas accounting practices for material, labor, etc.

(f) Tax should be allowed as a deduction allowance factor. FERC recognizes tax in its tariffs.

(g)(2) This change is equitable and recognizes the new capital investment of a purchaser of a depreciated line.

(g)(3) Present wording appears to require depreciation to zero then back up to 10%. Suggest rewording to remove ambiguity as follows:

> "The transportation calculation will continue to include in the allowance calculation a cost equal to ten percent (10%) of total capital investment in the pipeline even though the pipeline has depreciated to 10% or less of the total capital cost incurred to construct and install it."

"Total capital" clarifies the concept of all costs of the pipeline, so that later capital costs for additions and modifications are also included in the 10%. Pipeline in lieu of system clarifies that this does not apply just to complete offshore systems but to all lines qualifying for transportation allowances.

(h) The appropriate rate of return is at least two times S&P BBB Bond rate. A higher rate is needed to account for return on capital investment and risks of under-utilization of capacity and oil spill and property damage.

<u>Miscellaneous</u>

For transportation allowance, MMS should specifically allow itself authority to agree to other specific arrangements if they are equitable.

206.112
Clarify that location and quality differential are accepted in arrangements other than Exchange Agreements.

(b) Clarify that a request related to non-arm's-length transportation allowance would be an appealable decision as was stated in the Houston workshop and clarify it will not fall under the ordinary valuation provisions of §206.107.

206.118
The automatic disqualification of actual and/or theoretical losses in non-arm's-length transportation allowance while allowing them in arm's-length is arbitrary. Some criteria for disqualifying them in non-arm's-length should be stated other than mere affiliate relationship.

206.119
Tariffs require recognition of pipeline losses and are included in them. This again raises issue of unlawful discrimination in transportation prohibited by §5(e) and (f) of OCSLA and violates MMS duty to cooperate with its sister agency FERC on setting value for transportation under OCSLA.